Air Quality Permitting
Statement of Basis

May 1, 2006

Permit to Construct No. P-050055

Tesoro Refining and Marketing Company
Boise, Idaho

Facility ID No. 001-00093

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Final

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Acronyms, Units, and Chemical Nomenclature

AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
HAPs	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/scf	pounds per standard cubic foot
lb/MMBtu	pounds per million British thermal units
MACT	Maximum Achievable Control Technology
mg/l	milligram per liter
MMBtu	million British thermal units
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	oxides of nitrogen
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	permit to construct
Section	refers to the indicated section of IDAPA 58.01.01
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SM	synthetic minor
SO_2	sulfur dioxide
Tesoro	Tesoro Refining and Marketing Co.
TOC	total organic compounds
UTM	Universal Transverse Mercator
VCU	vapor combustion unit
VOC	volatile organic compound

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01.200, Rules for the Control of Air Pollution in Idaho, for issuing permits to construct.

2. FACILITY DESCRIPTION

Tesoro's Boise facility is a bulk gasoline terminal that receives liquid petroleum products via pipeline. The liquid products are stored on site in storage tanks and are transferred from the storage tanks to mobile tank trucks through a loading rack. Loading arms on the loading rack dispense the liquid product into the mobile tank trucks. When gasoline is loaded into mobile tank trucks, the vapors are collected in a vapor collection system and are oxidized in a vapor combustion unit.

3. FACILITY / AREA CLASSIFICATION

Tesoro's Boise facility is not a major as defined by IDAPA 58.01.01.205, nor is it a designated facility as defined by IDAPA 58.01.01.006.26. The facility is not a Tier I major facility as defined by IDAPA 58.01.01.008.10 for any criteria air pollutant, individual HAP, or combination of HAP's. The SIC code defining the facility is 5171, *Petroleum Bulk Stations and Terminals*.

The facility is subject to the requirements of 40 CFR 60, Subpart XX, *Standards of Performance for Bulk Gasoline Terminals*, because the loading rack was modified in 2003. The loading rack is the affected facility at a bulk gasoline terminal. The affective date of Subpart XX for new affected facilities is December 17, 1980.

The facility is not subject to any NESHAP (40 CFR 61) or MACT (40 CFR 63) requirement. Because this facility is a minor facility in terms of HAP emissions, the requirements of 40 CFR 63, Subpart R, *National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)*, do not apply.

This facility is located in Boise, Idaho which is located in Northern Ada County. Northern Ada County is located within AQCR 64 and UTM zone 11. This area is classified attainment for PM_{10} and CO, and unclassifiable for all other criteria air pollutants. There are no Class I areas within 10 kilometers of the facility.

The facility's AIRS classification is synthetic minor (SM) because enforceable limits limit the facility's potential to emit below all Tier I operating permit major source thresholds. The AIRS information for each regulated air pollutant emitted by Tesoro is provided in Appendix A. This information is entered into the U.S. EPA AIRS database.

4. APPLICATION SCOPE

On December 6, 2005, Tesoro submitted an air quality permit application to revise several conditions in its existing permit to construct. Emissions do not increase as a result of this permitting action. Note, a couple of the requests are modification without any supporting documentation; therefore, DEQ cannot grant these requests. Please refer to Section 5.5 of this document for each requested revision and DEQ's response to each request.

4.1 Application Chronology

December 6, 2005	DEQ receives a PTC application from Tesoro to revise the facility's existing PTC No. P-030041, issued August 18, 2003.
February 16, 2005	DEQ determines Tesoro's application complete.
March 10, 2006	DEQ provides a draft permit to the facility for review and comment.
March 10, 2006	DEQ provides a draft permit to its Boise Regional Office for review and comment.

5. PERMIT ANALYSIS

This section of the Statement of Basis describes the regulatory requirements for this PTC action.

5.1 Equipment Listing

No new equipment is being constructed and no existing equipment is being modified by this permit revision.

5.2 Emissions Estimates

Emissions are not increasing as a result of this permit revision; therefore, an updated emissions inventory is not required.

5.3 Modeling

Emissions are not increasing as a result of this permit revision; therefore, ambient air quality modeling is not required.

5.4 Regulatory Review

This section describes the regulatory analysis of the applicable air quality rules with respect to this PTC.

IDAPA 58.01.01.209.04 Revisions of Permit to Construct

Tesoro has requested that DEQ revise several conditions in its existing PTC. Emissions do not increase as a result of any revision; therefore, the application does not need to be provided for an opportunity for public comment.

IDAPA 58.01.01.300 Procedures and Requirements for Tier I Operating Permits

Tesoro's Boise facility was subject to Tier I operating permit requirements until construction activities allowed by a PTC issued in 2003, were completed in 2004. The 2003 PTC, as well as this revised PTC No. P-050055, makes enforceable the requirement to construct and operate a vapor collection system/vapor combustion unit (VCU) on the facility's loading rack when loading gasoline. In addition to the requirement to install the VCU, the PTC requires that total organic compounds (TOC) from the VCU not exceed 35 milligrams per liter of gasoline loaded (35 mg/l). Performance testing was required to measure the emissions to demonstrate compliance with the emissions standard.

The results of the performance test show that the TOC emissions measured during the test were below the emissions standard. This being the case, and given that gasoline throughput is limited by the PTC, the facility's potential to emit is less than all Tier I major source levels. Consequently, the facility is no longer subject to Tier I operating permit requirements.

In the same application submitted for this PTC revision, Tesoro requested that DEQ terminate its Tier I operating permit for its Boise terminal. DEQ terminated that permit on January 23, 2006.

40 CFR 60 New Source Performance Standards

In 2003, Tesoro submitted a permit to construct application to add an additional loading arm to the loading rack. The modification to the loading rack triggered the requirements of 40 CFR 60, Subpart XX, *Standards of Performance for Bulk Gasoline Terminals*. The effective date of Subpart XX is December 17, 1980. Subpart XX requires that each affected facility (the total of all the loading racks at a bulk gasoline terminal) be equipped with a VCU designed to collect and oxidize the TOC vapors displaced from tank trucks during product loading. TOC emissions are limited to 35mg/l of gasoline loaded. Performance testing is required for compliance demonstration.

A performance test was conducted on the VCU on September 27, 2005, to satisfy the testing requirement. The results of the test show that the TOC emissions were less than the emissions standard during the test.

5.5 Permit Conditions Review

The following list of permit conditions is that requested by Tesoro to be revised. DEQ's response to each request immediately follows and is bolded to clearly separate response from request.

1. Permit Condition 1: Permit to Construct - Purpose

   Amend this section to include a statement regarding the facility's classification as a minor source.

DEQ added a sentence to the scope of the permit indicating the following: "This facility is not a *Tier I Source* as defined by IDAPA 58.01.01.006.101 because its potential to emit is limited to less than all *Major Facility* criteria listed in IDAPA 58.01.01.008.10. Therefore, the facility is not subject to the requirements and procedures contained in IDAPA 58.01.01.300-397."

2. Permit Condition 2.1: Process Description

   The terminal's loading rack consists of three loading bays or loading spots.

DEQ revised the description of the loading rack to indicate it has three loading "bays" instead of three loading "arms."

3. Permit Condition 2.2: Emissions Control Description

   The vapor combustion system includes the VCU as defined in the first paragraph of Condition 2.2. Since vapors are always being collected during truck loading operations, the lower maximum capacity limit is not applicable.

Emissions are based on the total amount of gasoline loaded, and that total is limited in the PTC. Therefore, the lower bound has no affect on the facility's potential to emit. Therefore, DEQ has removed the lower bound from the control device description as requested.

4. Permit Condition 2.3: Particulate Matter Emissions Limits for Incinerators

   DEQ's Air Quality Permitting Technical Analysis dated April 22, 2003 which was attached to PTC P-020052 states, ". . .the source is inherently in compliance with the PM emissions standard in Section 786, and no demonstration of compliance is required in the PTC."

In order to better facilitate compliance evaluations, either internal or jurisdictional, Tesoro proposes to either modify this condition to include a statement referencing the Technical Analysis, as indicated in the attached revised PTC, or attach the April 23, 2003, Technical Analysis to the current permit.

The only source of particulate matter is from the combustion of natural gas in the VCU's pilot flame. There is no particulate matter in the gasoline vapor. The following analysis reasserts DEQs regulatory determination that the vapor combustion unit is inherently in compliance with Section 786.

Given: **natural gas is primarily methane**

the density of methane is 0.0448 lb/scf [1]

the emission factor for PM from natural gas combustion is 7.6 lb/MMscf [2]

$$\frac{\mathbf{7.6\ lb\ PM/MMscf}}{\mathbf{0.0448\ lb/scf}} = \mathbf{1.7E\text{-}04\ lb\ PM/lb = 1.7E\text{-}02\ lb\ PM/100\ lb}$$

The PM emissions standard is 0.2 lb PM/100 lb of refuse (gasoline vapor in this case) combusted. It can be reasonably assumed that PM emissions from the VCU can never exceed the emissions standard provided: 1) the VCU is operated according to the manufacturer's specifications and recommendations, and 2) the VCU is operated in compliance with the operating, monitoring, and recordkeeping requirements contained in the PTC. For these reasons, monitoring and recordkeeping of any operating parameters are not specifically required to demonstrate compliance with Section 786. The supporting documentation as indicated in the footnotes is presented as Appendix B. This determination is made in lieu of Tesoro's request.

5. Permit Condition 2.4: Visible Emissions Limit

DEQ's Air Quality Permitting Technical Analysis dated April 22, 2003 which was attached to PTC P-020052 states, "... this source should inherently be in compliance with the opacity standard, and no demonstration of compliance is required in the PTC."

In order to better facilitate compliance evaluations, either internal or jurisdictional, Tesoro proposes to either modify this condition to include a statement referencing the Technical Analysis, as indicated in the attached revised PTC, or attach the April 23, 2003, Technical Analysis to the current permit.

Compliance with Section 625 is inherently demonstrated by combusting natural gas, and in this case, also by oxidizing gasoline vapors. With the exception of oxidizing the gasoline vapors, DEQ has set the precedent that a source that combusts natural gas is inherently in compliance with Section 625 and that no specific monitoring or recordkeeping requirements are needed to demonstrate compliance with Section 625. DEQ also asserts, in this case, that oxidizing the gasoline vapors in addition to combusting natural gas in the pilot flame inherently is in compliance with Section 625. This determination is made in lieu of Tesoro's request.

[1] Physical Properties of Industrial Gases and Common Industrial Chemicals, Universal Industrial Gases, Inc., Easton, PA, via internet, 3/06

[2] Compilation of Emission Factors 5th Edition, U.S. EPA, (Natural Gas Combustion, Section 1.4), 7/98

6. Permit Condition 2.7: Vapor Combustion System Requirements

Permit condition 2.7 requires the following:

At all times when any gasoline tank truck, as defined in 40 CFR 60.501, motor gasoline loading operation is conducted at the loading rack, the vapor combustion system shall be in operation with a pilot flame present.

Tesoro will schedule semi-annual maintenance activities during non-peak hours and prohibit motor gasoline loading while the vapor combustion system is not operating. However, the potential for unanticipated maintenance exists do to a malfunction of the vapor combustion system or other unforeseen circumstance.

Tesoro requests consideration to conditionally allow motor gasoline loading during unscheduled maintenance activities. Gasoline loading during this time would be restricted by a throughput limitation. This activity would require monitoring and recordkeeping requirements already required by the permit; specifically, those required by Condition 2.18.

Tesoro has completed preliminary air emissions calculations for the loading of gasoline during unanticipated maintenance activities. The loading of 800,000 gallons of gasoline while the vapor combustion system is not in operation results in approximately 2 tons of VOCs emitted. Tesoro is confident this emission would not jeopardize the terminal's synthetic minor status. Tesoro proposes to modify this condition by the addition of an unscheduled maintenance condition.

Startup, shutdown, and malfunctions are already addressed by Permit Condition 2.18. With respect to allowing gasoline to be loaded while the VCU is down, DEQ cannot make a determination, nor allow this proposal, at this time because Tesoro has not submitted an application for the modification.

7. Permit Condition 2.7.1: Vapor Combustion System Requirements – Unanticipated Maintenance – NEW CONDITION

In the event the vapor combustion system malfunctions and unanticipated maintenance is required, Tesoro will restore the system as expeditiously as possible. Gasoline loading may continue with a maximum of 800,000 gallons of gasoline loaded while the vapor combustion system maintenance is being completed.

During anytime when gasoline loading occurs while the vapor combustion system is not operating, the records requirements of Condition 2.18 are required.

Refer to DEQ's response immediately above.

8. Permit Condition 2.8: Product Loading Limit

Tesoro proposes revising this condition to limit the product types to those with volatility less than gasoline. By limiting the product types to those with volatility less than gasoline, the intent of the PTC condition is maintained. Tesoro believes the intent of this condition is to ensure the TOC emissions are not increased should product other than those listed be dispensed at the rack.

DEQ has revised the permit as requested.

9. Permit Condition 2.12: Vapor Combustion System Monitoring

Subsection 2.12.1 defines the recordkeeping requirements should the pilot flame not be present during "loading rack operations". Permit condition 2.7 requires the vapor combustion system to be operating with the pilot flame present during gasoline loading, but does not require the vapor combustion system to be operating with the pilot flame present during loading of other products.

Tesoro proposes changing this condition to require recordkeeping when the pilot flame is not present during motor gasoline loading.

DEQ has revised the permit as requested.

10. Permit Condition 2.2 0: National Emission Standards for Hazardous Air Pollutants for Gasoline Distribution Facilities – Non-Applicability -- NEW CONDITION

Tesoro proposes adding a new condition that clearly defines the inapplicability of 40 CFR 63 Subpart R. Subpart R only applies to major sources and, with a completed and accepted VCU source test, Tesoro's Boise facility is a minor source.

The PTC scope clearly indicates that Tesoro's Boise facility is a minor source. 40 CFR 63, Subpart R applies only to those sources that are major for HAP emissions. Because this facility is a minor source of HAP emissions, the requirements of 40 CFR 63, Subpart R do not apply. DEQ prefers to only include applicable requirements in any permit to construct; therefore, DEQ declines putting a non-applicable requirement in the revised PTC.

6. PERMIT FEES

Permit to construct application fees and processing fees do not apply to permit revisions.

7. PERMIT REVIEW

7.1 Regional Review of Draft Permit

DEQ's Boise Regional Office was provided the draft permit for review on March 10, 2006. No comments were provided.

7.2 Facility Review of Draft Permit

The facility was provided the draft permit for review on March 10, 2006. One comment was provided and incorporated into the permit.

7.3 Public Comment

An opportunity for public comment period is not required in accordance with IDAPA 58.01.01.209.04 because emissions are not increasing.

8. RECOMMENDATION

Based on review of application materials, and all applicable state and federal rules and regulations, staff recommends that Tesoro Refining and Marketing Co. be issued final PTC No. P-050055 for its Boise bulk gasoline terminal. No public comment period is recommended, no entity has requested a comment period, and the project does not involve PSD requirements.

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Appendix A

Tesoro Refining and Marketing Co.
Boise Bulk Gasoline Terminal

P-050055

AIRS Information

AIRS/AFS[a] FACILITY-WIDE CLASSIFICATION[b] DATA ENTRY FORM

Facility Name: Tesoro Refining and Marketing Co.
Facility Location: Boise, Idaho
AIRS Number: 001-00093

AIR PROGRAM / POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	SM80	TITLE V	AREA CLASSIFICATION: A-Attainment, U-Unclassified, N- Nonattainment
SO_2	B							U
NO_x	B							U
CO	B							A
PM_{10}	B							A
PT (Particulate)	B							U
VOC	SM						SM	U
THAP (Total HAPs)	B							U
			APPLICABLE SUBPART					
			XX					

[a] Aerometric Information Retrieval System (AIRS) Facility Subsystem (AFS)

[b] AIRS/AFS Classification Codes:

- A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For HAPs only, class "A" is applied to each pollutant which is at or above the 10 T/yr threshold, or each pollutant that is below the 10 T/yr threshold, but contributes to a plant total in excess of 25 T/yr of all HAPs.
- SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.
- B = Actual and potential emissions below all applicable major source thresholds.
- C = Class is unknown.
- ND = Major source thresholds are not defined (e.g., radionuclides).

Appendix B

Tesoro Refining and Marketing Co.
Boise Bulk Gasoline Terminal

P-050055

Supporting Information for Section 786 Compliance Demonstration

Standard Industrial Classification (SIC) System Search

STATISTICS & DATA | SIC MANUAL

This page allows the user to search the 1987 version SIC manual *by keyword*, to access descriptive information for a *specified 2,3,4-digit SIC*, and to examine the manual structure.

Enter a SIC CODE: 5171

Enter the search keyword(s):

Submit Clear

Search Help and Examples

- 5171 Petroleum Bulk stations and Terminals

Occupational Safety & Health Administration
200 Constitution Avenue, NW
Washington, DC 20210

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

1.4.3 Emissions[3-4]

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how "good" the factor is, with "A" being excellent and "E" being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

- Text was revised concerning Firing Practices, Emissions, and Controls.
- All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

- Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6\ m^3$, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_x emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_x emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6\ m^3$, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6\ scf] = (3.67)\ (CON)\ (C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4\ lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

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Universal Industrial Gases, Inc.

Physical Properties of Industrial Gases and Common Industrial Chemicals

(English Units)

			Normal Boiling Point (1 atm)		Gas Phase Properties @ 32°F & @1 atm			Liquid Phase Properties @ B P& @ 1 atm		Triple P	
			Temp.	Latent Heat of Vaporization	Specific Gravity	Specific Heat (Cp)	Density	Specific Gravity	Specific Heat (Cp)	Temp.	P
Substance	Chemical Symbol	Mol. Weight	°F	BTU/lb	Air = 1	BTU/lb °F	lb/cu. ft	Water = 1	BTU/lb °F	°F	
Air	–	28.98	-317.8	88.2	1	0.241	0.08018	0.873	0.4454	-352.1	
Oxygen	O_2	32.00	-297.3	91.7	1.113	0.2197	0.089212	1.14	0.4058	-361.8	(
Nitrogen	N_2	28.01	-320.4	85.6	0.9737	0.249	0.07807	0.806	0.4877	-346.0	
Argon	Ar	39.95	-302.6	69.8	1.39	0.125	0.11136	1.4	0.2575	-308.8	
Carbon Dioxide	CO_2	44.01	-109.3[a]	245.5[b]	1.524	0.199	0.12341	1.18[c]	–	-69.9	
Hydrogen	H_2	2.02	-423	191.7	0.06998	3.425	0.005611	0.071	2.309	-434.8	
Carbon Monoxide	CO	28.01	-312.7	92.79	0.9736	0.2478	0.07806	0.79	–	-337.1	
Water	H_2O	18.02	212	970.6	–	0.8784[d]	0.0368[d]	0.95855	1.007	32.0	
Methane	CH_4	16.04	-258.68	219.22	0.559	0.593	0.0448	0.425	0.8314	-296.5	
Ammonia	NH_3	17.03	-28	589.3	0.6003	0.520	0.04813	0.6819	–	-107.9	
Helium	He	4.00	-452.06	8.72	0.139	1.25	0.01114	0.124	1.086	NONE	
Neon	Ne	20.18	-410.9	37.08	0.701	0.25	0.05621	1.207	0.4483	-415.4	
Krypton	Kr	83.80	-244	46.2	2.887	0.06	0.2316	2.41	0.1273	-251.3	
Xenon	Xe	131.30	-162.8	41.4	4.55	0.038	0.365	3.06	0.08121	-169.2	
Ozone	O_3	47.99	-168.3	6530	1.658	9.41	–	1.352	–	-314.5	
Hydrogen Sulfide	H_2S	34.08	-76.4	235.6	1.196	0.245	0.09608	0.9136	–	–	
Sulfur Dioxide	SO_2	64.06	14	167.5	2.279	0.149	0.18272	1.46	–	-103.9	·
Ethane	C_2H_6	30.07	-127.53	210.41	1.056	0.366	0.08469	0.546	–	-297.9	
Ethylene	C_2H_4	28.05	-154.8	208	0.978	0.399	0.07868	0.567	–	-272.5	
Acetylene	C_2H_2	26.04	-118.4[a]	264[c]	0.906	0.383	0.07314	0.613	–	-116.0	
Propane	C_3H_8	44.10	-43.67	183.05	1.573	0.388	0.1261	0.58	–	–	
Propylene	C_3H_6	42.08	-53.9	188.18	1.481	0.366	0.11249	0.61	–	–	
Methanol	CH_3OH	32.04	148.2	473	–	0.3274	49.44[d]	0.795	0.6055	-143.4	

[a] Sublimation point [b] Sublimation Enthalpy [c] Triple point [d] Boiling point

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